BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking Regarding Policies, Procedures and Rules for Development of Distribution Resources Plans Pursuant to the Public Utilities Code Section 796	Rulemaking 14-08-013 (filed August 14, 2014)

PETRA'S RESPONSES TO QUESTIONS POSED IN THE COMMISSION'S ORDER INSTITUTING RULEMAKING REGARDING POLICIES, PROCEDURES AND RULES FOR DEVELOPMENT OF DISTRIBUTION RESOURCES PLANS

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I. **Introduction**

On August 20, 2014, the Commission issued an Order Instituting Rulemaking ("OIR") in the above-captioned proceeding and invites parties to respond to 16 questions and also comment on procedural issues.

Petra is a provider of intelligent technology solutions and systems that include distributed and pole-mounted solar, energy storage, and energy efficiency controls that can directly support the Commission's goal of minimizing overall system costs and maximize ratepayer benefit from investments in distributed resources. Petra's systems also benefit communities through leverage of their communications networks to support community-wide broadband access. Petra is committed to both renewable technology that lowers greenhouse gas emissions and also to innovation that supports grid health and resiliency at the distribution edge.

II. **Responses to the OIR Questions**

Petra is pleased to respond to the questions posed by the OIR.

1) What specific criteria should the Commission consider to guide the IOUs' development of DRPs, including what characteristics, requirements and specifications are necessary to enable a distribution grid that is at once reliable, safe, resilient, cost-efficient, open to distributed energy resources, and enables the achievement of California's energy and climate goals?

The Commission should consider that distributed energy resources are an important factor in supporting a robust and resilient grid. Petra's technology offers not only distributed and clean energy supply technology it can also provide flexible Volt/VAr support to cost-effectively manage distribution feeders. There are many areas in the U.S. experiencing a proliferation in distributed *energy. The Commission is encouraged to investigate and encourage "best practices" from other regions, such as New York, the mid-Atlantic (PJM), and Texas that are similarly working on this challenge. In addition to 'best practices' the Commission should focus on keeping barriers to entry low and challenge underlying assumptions that may bias outcomes against new technology. Tariffs and metering are of primary importance. Other regions have successfully adopted new methods that depart from 'business as usual,' making them more workable for distributed technology solutions. Some examples are allowing alternatives to real-time information from small behind-the-meter resources, or allowing the use of new metering technologies and systems to provide critical information. Regions that have harmonized distributed energy into their grid management toolkits have successfully relied on these resources and experienced many instances where distributed resources are "over performing" from initial expectations. Setting the requirements for small distributed energy resources to be similar to large supply resources is unnecessary. The Commission should encourage pilot programs to test assertions and demonstrate the benefits of aggregation, new distributed metering technologies, and advanced control systems to support grid operations and planning. Tariffs should be similarly aligned*

2) What specific elements must a DRP include to demonstrate compliance with the statutory requirements for the plan adopted in AB 327?

The DRP should include elements that lead to lower distribution system costs that ensure reliable electric services at the lowest possible costs. These elements may include the advancement and deployment of technologies that leverage existing infrastructure and combine various distributed energy technologies such as generation, storage, and efficiencies within a single project. By leveraging existing infrastructure, deployment costs will be lower and solutions delivered faster. For example, when deploying distributed solar generation on existing streetlights or utility poles the balance of system cost and interconnection costs should be very low as most of the infrastructure is already in place. DRP systems can leverage a portfolio of technologies to manage supply, storage and consumption to best support the reliability and resiliency of the grid.

3) What specific criteria should be considered in the development of a calculation methodology for optimal locations of DERs?

The Commission should ensure that all the benefits of grid support are included in the methodology. Resources that can provide on-peak and off-peak energy management and VAr support could help to optimize the capital and operational costs of the distribution network. The Commission should insist on transparency for valuation based on grid health over both the short run and long run. It is important to allow flexibility when considering long-term optimization for locations of DERs as the needs of the grid can change quickly. The Commission can support the development of "heatmaps" showing were distributed solutions would be needed most and a process by which technology providers can leverage incentives. The DRPs already have a good sense of what locations would benefit from technology deployment. Many technologies are *already available for deployment so the Commission should supplement any long-term planning with short term energy and voltage signals. These can be based on the wholesale markets and grid reliability signals from the California ISO or a locally provided signal.*

4) What specific values should be considered in the development of a locational value of DER calculus? What is optimal means of compensating DERs for this value?

Approximate locational value can be based on a calculation of the wholesale energy prices which are adjusted for customer loss factors, power factors, or power quality considerations, including Volt/VAr support needs. The Commission should also consider the value of additional flexible ramping capability which is only needed during short windows of time and can be much more cost-effective than turning on a power plant for an entire day to provide ramping for a few hours. The Commission should not make the calculations too complex as to thwart meaningful progress by early innovators and should insist that the values update frequently.

5) What specific considerations and methods should be considered to support the integration of DERs into IOU distribution planning and operations?

Better valuation of the need for additional reliability services for firming such as Volt/VAr control and short-term fast ramping capability is encouraged. The Commission should consider the flexibility that the DER brings in terms of ability to generate on-demand or to time shift energy production to support system load factor by peak shaving and valley filling and covering crossover renewable fuel periods by providing ramping services.

The Commission should also consider the benefits of DER portfolios that include multiple technologies, especially those that leverage existing infrastructure. Striking the balance between economy and complexity will be important.

6) What specific distribution planning and operations methods should be considered to support the provision of distribution reliability services by DERs?

Passing through a signal from the CAISO or creating a local control signal should unleash additional untapped control capabilities where parties can provide flexible operation with appropriate compensation. Distribution planning should consider individual phase loading and the value in balancing phase loadings on a static and dynamic basis to reduce losses and neutral voltage rise. Distribution planning should also consider the value of DERs in their ability to self-limit during fault conditions or to contribute to fault current if necessary to assure proper coordination. Intelligent DERs can sense system conditions such as low grade faults that are not readily measured at the substation. These capabilities should be considered first-order tools to improve the reliability and responsiveness of the network. Distribution Planning should fully utilize the capabilities of DERs to provide system diagnostics.

7) What types of benefits should be considered when quantifying the value of DER integration in distribution system planning and operations?

Benefits should accrue when and where the products and services fill customer needs and should value the additional benefits of grid reliability services. Distributed resources can offer non-energy benefits, such as reactive power Volt/VAr support, and distributed monitoring/system intelligence. Recognizing and valuing these benefits is an important step toward encouraging innovation and engaging distributed energy resources. The Commission should foster simplicity in tariff designs for ease of customer adoption. The benefits of the avoided distribution system costs associated with the DERs should be considered. Any diagnostic capabilities from the DER's should also be considered and leveraged. Renewable energy credits should be offered for distributed renewable energy solutions.

8) What criteria and inputs should be considered in the development of scenarios and/or guidelines to test the specific DER integration strategies proposed in the DRPs?

Demonstration projects and pilot programs should be undertaken to understand technology integration, identify challenges to larger scale deployment, reveal barriers to entry and encourage innovation. It is the purpose of DERs to bolster grid health and The Commission should encourage research about the customer experience and the distribution owner/operator experience. Evaluating scenarios of existing DERs that are already installed and have been installed through various grid events can inform the development of scenarios to evaluate future strategies. There are numerous systems that have been through significant events such as Hurricane Sandy. The valuable information based on actual performance of these systems in real life conditions should inform forward-looking distribution planning.

9) What types of data and level of data access should be considered as part of the DRP?

The DRP should act as an information hub fostering transparency. Barriers to entry should be kept low to offer solution providers the ability to react based on this information. Grid reliability signals that are tied to the physical condition of the grid can be, but do not have to be, market based but must accurately portray what is needed from technology providers. Data access should be transparent and afforded both the system designer and the utility. The utility should have reach into the real-time monitoring to mine the data that they need to support the operations, safety and reliability of the network.

10) Should the DRPs include specific measures or projects that serve to demonstrate how specific types of DER can be integrated into distribution planning and operation? If so, what are some examples that IOUs should consider?

The DRPs should encourage and support all types of technologies that provide grid reliability benefits. Especially useful are demonstrations where aggregated information can be used for small resources. Where meaningful relief can be provided in real time and measured after-the-fact, a closer look is helpful to lowering the barriers to entry and the cost of incorporating the *technology. Smaller solutions should be afforded the ability to aggregate to a level that keeps their costs low. As previously mentioned, DRPs should include several demonstration projects to test and validate various technologies.*

11) What considerations should the Commission take into account when defining how the DRPs should be monitored over time?

Grid health can be monitored over time beginning with traditional distribution system reliability metrics. Most of the Western Interconnection is implementing a system wide deployment of synchrophasors to measure grid health. The Commission may want to encourage the inclusion of this information or the addition of synchrophasors in strategic locations on the distribution system.

12) What principles should the Commission consider in setting criteria to govern the review and approval of the DRPs?

Review and approval of DRPs should be predicated upon the ability to perform necessary reliability functions, the capability of managing a robust data platform, and disinterest in market outcomes to assure fair and unbiased treatment when working with technology innovators.

13) Should the DRPs include discussion of how ownership of the distribution may evolve as DERs start to provide distribution reliability services? If so, briefly discuss those areas where utility, customer and third party ownership are reasonable?

Taking a chapter from the wholesale marketplace, the reliability operators are independent from the delivery asset owners which are independent from the market participants. In other regions it has not been demonstrated as cost-effective to separate the distribution grid operator from the distribution grid asset owner. The Commission can explore to what degree separation is effective for the distribution operators to be independent from solutions providers to assure a level playing field distribution-level market participants.

14) What specific concerns around safety should be addressed in the DRPs?

Specific relaying and safety procedures should be maintained to assure personnel safety. Best practices such as those employed by utilities in New York should be examined.

15) What, if any, further actions, should the Commission consider to comply with Section 769 and to establish policy and performance guidelines that enable electric utilities to develop and implement DRPs?

A discussion of tariffs that align with and foster cost-effective distributed technologies should be included. The commission should consider establishing new meter standards that reflect the growing capabilities of technology to provide high accuracy data from non-traditional meters that are integrated in other components.

16) Appendix B to this rulemaking is a white paper that articulates one potential set of criteria that could govern the IOUs DRPs. Please review the attached paper and answer the following questions:

- Integrated Grid Framework: the paper opens by presenting an 'Integrated Grid Framework,' what additions or modifications would you suggest be made to this framework?

1) *The Integrated Grid Framework should be more action-oriented and outward-looking and has the potential to stifle innovation and creativity. Critical policy choices are embedded within – for example, to* ***foster*** *innovation and new business models or* ***accommodate*** *it? Do we want to* ***lower*** *emissions or* ***manage*** *emissions? While a systems engineering approach serves well in many situations, the wave of disruptive change upon us may require more.*
2) *The Integrated Grid Framework needs to be clear:*
   a) *The process starts with identifying the policy objectives as well as customer needs* ***to define system qualities*** *and by extension the system design along with operational requirements.*
   b) *The focus of this paper is* ***not to define "what we want to achieve"*** *as this has been clearly identified and codified in California law, regulation and standards. The focus is instead on the, "How are we going to execute on this vision?" considerations.*
3) *It is useful to consider all aspects of an Integrated Grid – how should we harmonize the supply, delivery and consumption of electricity? What data, information and technologies encourage producers and pro-sumers to efficiently and cost-effectively support grid reliability by assuring electrons are matched in production and consumption both temporally, geographically and with the right balance of stability and flexibility, all within the framework of California's policy objectives.*

- Integrated Distribution Planning: what, if any, additions or modifications would you suggest to the Integrated Distribution Planning section of this paper?

When forming ISO markets it was clear that an integrated planning process would never be nimble or smart enough to keep up with changing needs and technologies. To assume Integrated Distribution Planning would not experience the same challenges ignores the fundamental tenet of providing transparency so consumers can change behavior and technology providers and system operators can innovate to solve grid challenges. While appropriate to have a backstop planning process, just as there is on the transmission grid, it should be the ***backstop*** *and not the first choice as it has the potential to strand costs and become very inefficient in a dynamically changing environment. A system of incentives can be put in place where the risk of bad investment isn't always left with ratepayers. A framework and structured approach is essential to robust and meaningful planning but too much will overturn the desired outcomes of this proceeding. If the goal is to drive "Locational benefits", "Optimal location" and "Value optimization" then transparency, a flexible framework and a loose "hand on the reins" will bring the innovators and risk takers into the solution set to the benefit of customers.*

- Distribution System Design-Build: what, if any, additions or modifications would you suggest to the Distribution System Design-Build section of this paper?

  Seamless communication and data infrastructure are in exactly the right direction. We have learned from ISO markets that the value of the grid can change in the course of a few seconds or a few miles. It is unlikely that we can precisely engineer the value of the grid given the diversity of customers and customer values. ***A flexible framework where customers can use exactly as much of the grid as they value without shifting costs and obligations to others should be a fundamental underpinning of this proceeding****. An approach that ensures customers are not saddled with design-build decisions made by others that cannot anticipate their needs is needed. An important consideration is how costs get absorbed or allocated for poor design-build choices.*

- Integrated Distribution System Operations: what, if any, additions or modifications would you suggest to the Integrated Distribution System Operations section of this paper?

  The grid is connected from generators to customer devices. Seamless flows of information and a hierarchical framework are essential. Grid operators have a finite capacity to manage large volumes of data. On the high voltage system, the operators of the larger grids do not have "deep" visibility but assure good "handoffs" from higher to lower voltages. The model appears to be going in the right direction.

  Minimal DSO functions

  To assume there is a "sweet spot" that achieves Minimal DSO functions to ensure safe and reliable operations *may result in things falling between the cracks. Assuring the DSO does not have a vested interest in biasing operating outcomes, and is "disinterested", by "how" but keenly vested in "what" - reliable, yet economic, outcomes should be a foundational pillar. It is clear that the operational lines between transmission and distribution are continuing to blur. The transmission networks are growing more dependent on distribution connected resources for capacity, energy, voltage, and frequency control. Transparency between transmission and distribution operations will become more critical, thus increasing the value of distribution connected technologies. Distribution planning will need to also have a tighter link to transmission planning and transmission operations in order to ensure that the overall reliability and policy objectives are achieved.*

  Reliability coordination at Transmission to Distribution (T-D) interface *already occurs. The Commission should bolster communication and data transparency and knowledge transfer to assure coordination between operators and transparency to those wanting to respond to reliability signals.*

  Potentially expanded DSO roles as energy transactions across distribution grow.
  The key is in assuring even-handed treatment and a level playing field.

- Integration of DER into Operations: what, if any, additions or modifications would you suggest to the Integration of DER into Operations section of this paper?

  Given the current state of FERC Order 745 this should add a "continuously monitor" task to assure alignment with wholesale policies. A recognition that technology is moving quickly to provide solutions to the operational needs and that relying too much on historical precedents and regulations can serve as barriers to enhancements that will improve the operational performance and integrity of the grid. As an example, application of metering standards and the interpretation of the regulations regarding metering add significant and unnecessary cost to small scale distributed resources for no operational or system benefit.

- Integrated Grid Roadmap: what, if any, additions or modifications would you suggest to the Integrated Grid Roadmap section of this paper?

  There is increasing support for using DER and to truly understand the disruptive change being experienced should be a key underpinning. The Commission should ensure that the incumbent utilities have the opportunity and ability to lower barriers to entry for, and to collaborate with, providers of technologies for the benefit of the customers. The utilities are burdened with risk implications that are not present for other innovators. Bringing an equitable balance of information, valuation, and innovation should speed the adoption and integration of technologies that benefit the customers and forward policy goals in a harmonious manner.

Respectfully,

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